Pacific Gas and Electric Company

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July 22, 2005

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1D
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments on the June CEC staff report "Investor-Owned Utility Resource Plan Summary Assessment" and responses to the questions posed for the associated workshop conducted by the 2005 IEPR Committee on June 29, 2005.

Thank you for considering our comments. Please feel free to call me at (415) 973-6463 if you have any questions about this matter.

Sincerely,

Les Guliasi

LGG:pmm

Enclosure

PG&E Comments on Docket 04-IEP-1D

2005 IEPR Staff Report
Investor-Owned Utility Resource Plan Summary Assessment
June, 2005

Discussion Items from the June 29, 2005, IEPR Committee Hearing on the Investor-Owned Utility Resource Plan Summary Report

Overview

PG&E is pleased to provide comments on the California Energy Commission (CEC) Staff Report, Investor-Owned Utility Resource Plan Summary Assessment, June 2005. This report reviews resource plan data provided by investor-owned utilities in response to staff data requests. For PG&E, this includes cost data provided to the CEC in January, 2005; customer demand data provided in February, 2005; and supply and resource data submitted in March and April of 2005.

In addition to comments on the Staff Report, PG&E is also providing additional information requested by Commissioner John Geesman at the June 29, 2005, IEPR Committee hearing on the Investor-Owned Utility Resource Plan Summary Report. Specifically, PG&E is providing the following information:

- An explanation of PG&E's Least Cost/Best Fit Project Assessment Methodology

- An explanation of how PG&E applied the directive from the CPUC's December procurement decision making renewable procurement the "rebuttable presumption" in all procurement

- An explanation of how the "rebuttable presumption" was used in evaluating the Contra Costa 8 project

I. PG&E Comments on IEPR Staff Report

Investor-Owned Utility Resource Plan Summary Assessment

Energy Efficiency

Chapter 2 of the Report discusses Customer Energy Efficiency (CEE) forecasts and programs proposed by the IOUs. PG&E's comments address sections of the Report that err in characterizing PG&E's energy efficiency achievements and plans.

The staff Report states,

> "PG&E's reported uncommitted energy efficiency appears to lag the CPUC goals in 2013 by 1,286 GWh and 717 MW. A slower program ramp-up could account for the shortfall in savings. PG&E is trying a new mass market program approach for the residential and small commercial sector that could take time to develop. The program is responsible for more than half of their projected peak savings over 2006-2008." (p. 13)

This statement is inaccurate and should be revised, as staff acknowledged at the June 29, 2005, IEPR Committee Hearing. At that meeting, page 7 of the staff presentation contained the statement:

> "PG&E incorporates a lag factor and meets the goals when their internal assumptions about baseline program savings are used instead of staff's."

PG&E's energy and peak CEE savings expectations are wholly consistent with the CPUC savings targets, and PG&E is aggressively working to implement programs to achieve the targeted energy savings. The specific differences between CEC staff assumptions regarding CEE used for this report and PG&E's assumptions used in program design and funding are as follows:

- PG&E did indeed lag the targets by one year as a conservative approach. The one year lag accounts for the implementation of measures over time and is intended to forecast measurable savings rather than simply "committed to" measures.

- The 1,286 GWh difference between the CEC staff analysis and PG&E's submittal is due primarily to differences between the CEC's and PG&E's view of savings attributable to baseline programs. PG&E's analysis is that current baseline programs result in 527 GWh annual savings compared to CEC staff's analysis that baseline programs save 408 GWh annually. Over the eight-year period from 2006-2013 the difference between baseline program savings projections results in 952 GWh of the 1,286 GWh difference as shown on table 2-9 of the staff Report. The remaining difference is due to lagging the target savings by one year.

- The combination of the two elements, above, brings the 1,286 GWh gap to zero over the 8-year forecast horizon.

PG&E also disagrees with staff's assessment of long-term CEE savings by IOUs. A key finding in the staff Report concludes:

> "Reviewers of the IOU program portfolios are confident that the 2006-2008 programs will achieve the near term goals. The longer term goals, however, cannot be met without greater effort by the IOUs in creating more innovative programs, capturing comprehensive savings, and avoiding lost opportunities." (p. 12)

PG&E is committed to achieving its long-term targets and is actively developing programs to achieve this level of energy efficiency. PG&E has presented a new, market-based portfolio to the CPUC for approval which will make achieving the targets it has been set easier. This portfolio defines programs by customer-based decision makers, an approach that will support a more targeted approach to meeting customer's needs. The ramp-up required to attain the CPUC's long-term targets is well managed beginning with expanded programs in 2004 and continuing with increases in 2005 and proposed increases in 2006 and after. Commission staff must realize that post-2008 energy efficiency programs are not yet fully designed or funded; hence it is impossible to demonstrate conclusively that utilities will capture the savings targets.

Price Sensitive Demand Response

Chapter 3 of the Staff Report addresses the utilities' Price Sensitive Demand Response Program assumptions and projections. Staff notes, "There is a fundamental disconnect between the current IOU reporting of megawatts to be counted toward meeting the demand response goals set forth in D.03-06-032 and the need of resource planners for measurable and reliable load reduction." (p.43)

PG&E agrees with the staff assessment that there is currently a disconnect between the targeted demand response levels and dependable megawatt reductions. PG&E is committed to demand response and is actively working to enroll customers to participate in the various programs it has approval for. That said, if there is not sufficient program participation, or if voluntary reductions are not made by participants when they are needed, utilities will be required to serve more load than was planned for.

CEC staff may not fully understand PG&E's demand response forecast, based on a reading of the staff criticism of PG&E's demand response planning. The report states, "The S-1 filings from PG&E show the same level in all scenarios, so PG&E is not even acknowledging the difference between the resource planner's desire for realistic expectations that SCE and SDG&E address." (pp. 44-45)

The demand response program serves all system-level load customers, not simply bundled customer loads; hence the projection will not vary with the level of bundled customer loads served by PG&E. It is appropriate that the level of demand response doesn't change with varying load levels, as the system-wide requirements and demand response targets will not change.

Renewable Portfolio Standard and the Accelerated Renewables Scenario

Chapter 4 of the staff Report addresses renewable resource planning. The report notes that PG&E calculated its annual aggregate renewable resource percentage based on the previous year energy requirements, while other IOUs and staff used a percentage calculation based on current year retail demand to determine renewable resource requirements.

PG&E used the previous year energy requirements as the basis for developing its aggregate renewable resource percentage in order to ensure consistency between the annual procurement target (APT) and the aggregate RPS procurement target. Using prior year load targets ensures that the denominator of the renewable APT calculation and the RPS achievement calculation are comparable. Beyond 2010, PG&E maintains a minimum 20 percent RPS energy portfolio using either measurement.

Distributed Generation

In Chapter 5 of the Report, staff explains that California encourages Distributed Generation resources (DG) but has no mandates or specific goals for DG energy or capacity. For PG&E, staff concludes it cannot determine what PG&E's assumptions are regarding future DG installations or how they were developed. The report states, "It is not clear from the submitted information how PG&E arrives at its yearly forecasts. Staff analysis of actual public interconnection data for the years 2002-2004 shows an average monthly increase in nameplate capacity of 2.5 MW per month, with a cumulative installed capacity over this period of 164.5 MW." (p. 67)

PG&E wishes to clarify that its DG forecast assumptions are simply an extrapolation of the same historical data that staff cited in the Report. PG&E's submitted form S-1, line 19, shows that between September 2006 and September 2016 installed DG capacity is estimated to increase by a total of 304 MW. This amount represents average monthly growth in DG capacity of 2.5 MW.

Nuclear Unit Early Retirement

Chapter 7 of the staff report addresses a range of issues raised in the utility plan filings, including nuclear unit early retirement. The report indicates that the Forms and Instructions asked the three IOUs to address nuclear unit early retirement.

PG&E conducted a comprehensive review of alternatives to the steam generator replacement project at Diablo Canyon. The steam generator project is needed to avoid early retirement of the nuclear units. PG&E's analysis of alternatives can be seen in its Steam Generator Replacement project application submitted to the CPUC in A.04-01-009. Chapter 6 of PG&E's Application, "Diablo Canyon Steam Generator Replacement Projects Replacement Energy Costs," is attached to these comments.

II. Discussion Items from the June 29, 2005, IEPR Committee Hearing on the Investor-Owned Utility Resource Plan Summary Report

PG&E Least Cost/ Best Fit Project Assessment Methodology

In evaluating offers as Least-Cost/Best-Fit, PG&E primarily uses the following considerations: resource value (Market Valuation), how the resource meets the identified product needs and complements other resources in PG&E's electric supply portfolio (Portfolio Fit), Credit, Viability, Transmission Impact, Debt Equivalence Impact, Environmental Characteristics, Participant Qualifications, and Conformance with PG&E's non-price terms and conditions. Each criterion is discussed below.

Projects are assessed, using each criterion, with the final selection also being based on qualitative considerations, not one all-inclusive score that attempts to assign relative weights to dissimilar criteria. Qualitative considerations may include judgment whether overall portfolio composition is good, technological diversity and risk of the portfolio, the environmental justice effects of a plant, etc.

PG&E stresses that the Least Cost/Best Fit assessment is a dynamic process, in that the criteria are adapted to PG&E's specific resource procurement needs. PG&E procures resources at different times to fill particular portfolio needs; hence the resources that may be least-cost and best fit at one particular time or to fulfill one particular need may be wholly different at another time or to fulfill a different need.

Market Valuation refers to how an offer's cost compares to an offer's benefits, from a market perspective. An offer's cost is reflected in the offer's pricing. An offer's benefits are the market value of the energy, capacity, and ancillary services offered. These costs and benefits may include: fixed and variable costs; transaction costs, such as market bid-ask spreads; location-specific value, as represented by zonal or nodal price differentiation; and operating flexibility, as represented by option value. The risks and uncertainties associated with an offer's costs and benefits will be considered as part of Market Valuation. These costs and benefits do not include the particular costs and benefits associated with the offer's impact on PG&E's portfolio positions and possible attendant market transactions by PG&E.

An important component of market valuation benefit is operating flexibility. PG&E uses option valuation models to quantify how operating flexibility contributes to market valuation.

Portfolio Fit refers to how well an offer's features match PG&E's portfolio needs. In particular, the value of an offer's capacity, energy, and ancillary services is adjusted to account for PG&E's portfolio positions, including temporal and locational characteristics. Portfolio Fit accounts for an offer's contribution to flattening positions of PG&E's portfolio and the offer's impact on the distribution of PG&E's portfolio costs. Portfolio Fit thereby weighs an offer's costs and benefits in the context of PG&E's portfolio needs. In contrast, the Market Valuation component considers an offer's costs and benefits without taking into account PG&E's portfolio needs.

Credit refers to the participant's capability to perform all of its financial and other obligations under the contract agreements, including, without limitation, the participant's ability to provide performance assurance under the agreements. PG&E will consider the participant's financial strength, as determined by PG&E, as well as any credit enhancements acceptable to PG&E that the participant may offer with its proposal. PG&E will also consider its overall credit concentration with any particular participant.

Viability refers to the probability that the resource(s) associated with an offer can be financed and completed as required by the agreement and will be available to provide capacity and energy and/or ancillary services when called upon.

Transmission Impact refers to the effect of an offer on the electric transmission system. In evaluating an offer, PG&E will consider the network upgrade costs, congestion risk, impact on RMR costs, and other locational attributes associated with an offer.

Debt Equivalence in this context refers to the debt-like characteristics of PPAs not classified as interest bearing liabilities under Generally Accepted Accounting Principles. PG&E will consider the debt equivalent impacts of an offer.

Environmental Characteristics refer to air emissions, including carbon dioxide, nitrogen oxides, sulfur dioxide and particulates, and other potential environmental impacts. The quantities and potential costs to PG&E and to society associated with these characteristics will be considered.

Participant Qualifications refers to the experience and technical expertise of the participant putting forth the offer.

Conformance with PG&E's non-price terms and conditions refers to the degree to which the participant accepts PG&E's proposed terms and conditions. PG&E will evaluate offers in a manner consistent with the company's and the corporation's environmental and environmental justice policies.

How does PG&E go about applying the directive from the CPUC's December procurement decision that makes renewable procurement the rebuttable presumption in all procurement?

CPUC Decision 04-12-048 found that "...whenever an IOU issues an RFO for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers." (pg 77)

Renewable resources compete with each other in renewable-only RFOs. Renewable resources also compete with conventional resources in all-source RFOs. Renewable and non-renewable bids received in the same RFO are evaluated using the same least-cost, best-fit criteria discussed above.

Non-renewable bids are accepted only if their least-cost best-fit assessment is better than that of renewable bids received in the same RFO.

How was the rebuttable presumption of renewables analytic framework applied to the Contra Costa project?

As referenced above, the rebuttable presumption of renewables is a requirement of RFOs issued for generation resources. The Contra Costa 8 (CC8) generator was not solicited through an RFO. It was part of a comprehensive, multi-party settlement of issues that arose during the California energy crisis. PG&E filed an application with the CPUC for approval of the CC8 Asset Transfer Agreement as the result of the "Settlement and Release of Claims Agreement" executed by the CPUC, PG&E, and 5 other California parties. That Agreement, which was entered into by the CPUC on January 14, 2005, after D. 04-12-048 was issued, states that "The CPUC's execution of this agreement...shall constitute the Required Approval from the CPUC for all purposes of this Agreement,...shall constitute authorization for PG&E either to (a) acquire and take ownership of the CC8 assets..., or (b) receive the CC8 Alternative Consideration..." Rebuttable presumption was not part of the settlement agreement signed by the CPUC.

Nevertheless, if CC8 had been subjected to the rebuttable presumption requirement, it could have easily met that standard in all the criteria used to evaluate RFO responses.

Market Valuation: CC8 is a partially completed asset, acquired at a discount if compared to any other new resource. The initial in-service capital cost of CC8 is estimated to be $310 million, or $585/kilowatt in 2008 dollars. For reference, the in-service capital cost of the Market Price Referent, used in evaluating renewables, is $720/kW in 2004 dollars (approximately $764/kW in 2008 dollars).

Portfolio Fit: In its most recently approved long-term plan, PG&E identified a need for dispatchable resources. In approving PG&E's stated portfolio needs, the CPUC found "that PG&E's LTPP plan is reasonable and we approve PG&E's strategy...because it is compatible with PG&E's medium resource needs, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty." CC8 fills part of those approved needs. It is a dispatchable plant that can be operated in minimum load conditions in off-peak hours and is capable of duct-firing in peak hours to meet system peak load needs. CC8 will have an availability factor ranging from 92 percent to 95 percent. No cost-effective renewable resource can match those needed operating characteristics.

Credit: As an owned resource, credit is not an issue.

Viability: CC8 is a conventional combined cycle plant that uses a GE 7FA combustion turbine as its prime mover, a well-tested technology. Black and Veatch Construction, Inc., an internationally-recognized construction firm, will provide engineering, procurement, and construction services.

Transmission Impact: CC8 is located near PG&E's largest load center, the San Francisco Bay Area, and will enhance the reliability of the state's energy supply and provide more RMR options to the CAISO.

Debt Equivalence Impact: as an owned asset, CC8 has a positive debt equivalence impact.

Environmental Characteristics: CC8 is a repowering project on a brownfield site in an industrial area, which would have less environmental impact than any greenfield site, whether conventional or renewable. The CEC approved the project with conditions to mitigate environmental and community impacts, including the use of state-of-the-art Best Available Control Technology to minimize air emissions, the use of a cooling tower to minimize water quality impacts, and structural changes to reduce visual impacts. The completion of this clean, gas-fired central-station generating plant will help to promote the CEC's energy policies.

Participant Qualifications: as an owned asset, there are no issues with participant qualifications.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
DIABLO CANYON STEAM GENERATOR REPLACEMENT PROJECTS REPLACEMENT ENERGY COSTS

A. Introduction

The purpose of this chapter is to present Pacific Gas and Electric Company's (PG&E or the Company) cost estimates for purchasing replacement energy or building replacement generation, as alternatives to the proposed Steam Generator Replacement Projects (the Projects). That is, if the steam generators in Units 1 and 2 of the Diablo Canyon Nuclear Power Plant (DCPP) are not replaced as proposed in this application, and DCPP's generation units are forced to shut down, PG&E will need to purchase power or build new generation to serve the energy needs of PG&E's bundled service customers.

Specifically, this chapter explains the derivation of the market price forecasts used by the cost/benefit analysis presented in Chapter 5, "Cost/Benefit Analysis of the Diablo Canyon Steam Generator Replacement Projects." In addition, this chapter compares the cost of power purchases at the projected market prices against conservative estimates of the cost of building or purchasing from new resource alternatives to the proposed replacement of the DCPP's steam generators at DCPP Units 1 and 2. PG&E uses conservative or low alternative cost estimates to test the robustness of the proposed Projects. Finally, this chapter examines the sensitivity of alternative power costs to the future price of natural gas.

On March 26, 2004, PG&E updated its January 9, 2004 cost estimate of purchasing replacement energy or building replacement generation as alternatives to the Projects to account for two changes in assumptions regarding the operation of DCPP.[1] The two changes were: (1) an expected 20 MW increase in output from each of the DCPP units resulting from efficiency gains following replacement of the high and low pressure rotors for each Unit, and (2) the expectation of an approximate three-year extension to the operating license

[1] PG&E's initial estimate of the costs of purchasing replacement energy or building replacement generation as alternatives to the Projects was presented in Chapter 6 of its original testimony dated January 9, 2004.

of DCPP Unit 1, from September 21, 2021, to November 2, 2024. PG&E's original alternative energy cost estimate assumed the DCPP output would be 1100 MW per unit prior to the replacement of the high and low pressure rotors, and that DCPP Unit 1 would operate only until the end of its existing license life in 2021.

In this May 28, 2004, submittal, PG&E corrects the testimony, tables and figures to appropriately reflect an average DCPP energy output of 1110 MW.

This chapter is organized as follows:

- Section B—Summary of Results;
- Section C—Resource Alternatives Considered;
- Section D— Market Price Scenario;
- Section E— Combined Cycle Generation Cost Scenario;
- Section F— Combined Cycle and Renewable Generation Cost Scenario;
- Section G— Other Risks and Costs Associated with the Alternative Generation Scenarios; and
- Section H—Summary of the Alternative Cost Scenarios.

B. Summary of Results

The total cost of replacement energy, if the Projects are not pursued, is summarized below:

TABLE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE ALTERNATIVE RESOURCE COSTS
2003 PRESENT VALUE ($MILLION)

Line No.		Market purchases	Combined cycle (CC) generation ("100% CC")	90% CC plus 10% MW renewable generation
1	2003 PV	$3,148	$3,149	$3,135

As explained below for each of the generation alternatives, PG&E uses conservative assumptions that result in low alternative costs to test the robustness of the proposed Projects. In order to avoid getting into a debate about the most likely cost of new generation alternatives, PG&E relies on the California Energy Commission's (CEC) cost estimates of new generation technologies.[2] PG&E believes the CEC's estimates represent a low or optimistic view of the cost of new generation alternatives. However, as discussed in Chapter 5, even these low alternative costs significantly exceed the cost of the Projects by over $1.20 billion, making the Projects the preferred alternative.

C. Resource Alternatives Considered

In order to estimate the Projects' value, PG&E estimated the costs of replacement power under a broad range of scenarios.

1. Market Price Scenario

Under this alternative, PG&E would purchase power at forecast market prices from the dates when each of the DCPP Units 1 and 2 are shut down until the end of the license life. Without the Projects, the Diablo Canyon units are expected to shut down on the following dates:

- Unit 1: February 2, 2014; and
- Unit 2: February 3, 2013.

This alternative assumes that sufficient replacement power will be available to purchase 1,130 MW for Unit 1 and 1,130 MW for Unit 2 (the output of each Unit is expected to increase following the completion of the low pressure rotor replacement in 2006) in the marketplace. For purposes of estimating PG&E's alternative market purchase costs, PG&E has conservatively assumed that 2,200 MW of new merchant combined cycle generation will be added by the WECC market participants in anticipation of meeting demand growth and the forecasted shutdown of DCPP available when needed.[3] These market prices are those that were used throughout the cost-benefit analysis described in Chapter 5.

In Section G, PG&E assumes that new combined cycle generation is not available in time to replace DCPP's generation. The assumption that new combined cycle generation will be available when needed (rather than

[2] CEC Staff report dated August 2003 titled "Comparative Cost of California Central Station Electricity Generation Technologies".

[3] The additional 60 MW (the difference between DCPP's expected 2,260 MW output and the 2,200 MW of assumed new combined cycle generation) is assumed to come from existing or otherwise already planned resource additions.

constructed after the need becomes known when Units 1 and 2 are shut down) is conservative because it reduces the Projects' alternative cost.

2. Combined Cycle Generation Cost Scenario

Under this alternative, PG&E contracts or builds 2200 MW[4] of new combined cycle generation to be on-line by the date when the DCPP Units 1 and 2 are expected to be shut down if the Projects are not implemented. This alternative uses the CEC's construction cost assumptions for combined cycle generation. This alternative also assumes conservatively that such combined cycle generation is available immediately upon shutdown of Units 1 and 2, and is not available for operation before or after such replacement power is needed.

3. Combined Cycle and Renewable Generation Cost Scenario

Under this alternative, PG&E substitutes part of the new combined cycle generation in Alternative 2 with renewable generation when the DCPP Units 1 and 2 are shut down. PG&E provides a discussion of the incremental cost of renewable generation, relative to combined cycle generation, for wind, geothermal and solar renewable technologies. PG&E uses the CEC's renewable generation cost assumptions. This alternative also assumes conservatively that both combined cycle and renewable generation are available immediately upon shutdown of Units 1 and 2, and are not available before or after such replacement power is needed.

D. Market Price Scenario

Under this alternative, PG&E purchases power at forecast market prices from the expected dates when each of DCPP's Units 1 and 2 would be shut down if the steam generators are not replaced (Unit 1 on February 2, 2014, and Unit 2 on February 3, 2013) until the end of their expected license life.

1. Market Price Forecast

PG&E derives its market price forecast through MARKETSYM simulations using Henwood's Fall 2003 Western Electricity Coordinating

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[4] The additional 60 MW is assumed to be purchased from the market and the costs of doing so are included as a portion of the "operating costs" in Table 6-5.

Council (WECC) Reference Case, based on natural gas prices projected by PG&E.

PG&E uses scenario analysis to depict a plausible range of energy market prices by varying the natural gas prices used in the MARKETSYM simulations. The base case uses commodity gas prices based on the September 5, 2003, closing price of forward contracts traded in the New York Mercantile Exchange (NYMEX), plus location basis obtained from broker quotes for gas delivered at Topock, Malin and PG&E Citygate. Beyond 2008, PG&E extrapolates gas prices using the 1.1 percent rate, which corresponds to the escalation of the closing prices of the NYMEX natural gas forward contracts between 2006 and 2008.[5] The high case assumes natural gas prices are 40 percent higher than in the base case. The low case assumes natural gas prices are 40 percent lower than in the base case.

Table 6-2 provides the expected annual Northern California burner tip gas prices for years 2008 through 2027 for the three scenarios used.

[5] Escalation is calculated based on the September 5, 2003 closing prices of the NYMEX natural gas forward contracts between 2006 and 2008, the last three years of forward prices available in NYMEX.

TABLE 6-2
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL AVERAGE GAS PRICES, $/MMBTU

Line No.	Year	Base	High	Low
1	2008	$5.22	$7.31	$3.13
2	2009	$5.28	$7.39	$3.17
3	2010	$5.34	$7.48	$3.21
4	2011	$5.41	$7.57	$3.25
5	2012	$5.47	$7.66	$3.28
6	2013	$5.54	$7.76	$3.32
7	2014	$5.61	$7.85	$3.36
8	2015	$5.67	$7.94	$3.40
9	2016	$5.74	$8.04	$3.45
10	2017	$5.81	$8.14	$3.49
11	2018	$5.88	$8.23	$3.53
12	2019	$5.95	$8.33	$3.57
13	2020	$6.02	$8.43	$3.61
14	2021	$6.10	$8.53	$3.66
15	2022	$6.17	$8.64	$3.70
16	2023	$6.24	$8.74	$3.75
17	2024	$6.32	$8.85	$3.79
18	2025	$6.39	$8.95	$3.84
19	2026	$6.47	$9.06	$3.88
20	2027	$6.55	$9.17	$3.93

The resulting replacement energy prices for the scenario where there is capacity in the market available to meet the new 2,260 MW of demand resulting from shutdown of DCPP Units 1 and 2 is set forth in Table 6-3 below:

TABLE 6-3
PACIFIC GAS AND ELECTRIC COMPANY
ANNUAL AVERAGE NP15 7X24 ENERGY PRICES, $/MWH

Line No.	Year	Base	High	Low
1	2008	42.65	56.74	32.93
2	2009	45.58	60.64	35.00
3	2010	49.23	65.26	37.88
4	2011	51.87	68.63	39.93
5	2012	53.59	71.02	41.20
6	2013	55.35	73.37	42.57
7	2014	56.62	75.00	43.58
8	2015	57.69	76.42	44.33
9	2016	58.78	77.85	45.12
10	2017	59.80	79.25	46.00
11	2018	60.56	80.25	46.60
12	2019	61.33	81.26	47.21
13	2020	62.12	82.29	47.83
14	2021	62.91	83.33	48.46
15	2022	63.71	84.38	49.09
16	2023	64.48	85.35	49.72
17	2024	65.25	86.33	50.36
18	2025	66.03	87.32	51.00
19	2026	66.83	88.32	51.65
20	2027	67.63	89.33	52.31

2. Resulting Market Purchase Costs

The resulting replacement energy purchase costs for the scenario where there is capacity in the market available to meet the new 2,260 MW of demand resulting from shutdown of DCPP Units 1 and 2 is set forth in Table 6-4 below. Note that the average annual replacement purchase cost in Table 6-4 differs from the average 24-hour price in Northern California of Table 6-3 because the average replacement annual cost accounts for the DCPP generation pattern.

TABLE 6-4
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE MARKET PURCHASE COST

Line No.	Year	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$431,561	7,744	55.7
2	2014	$929,716	16,335	56.9
3	2015	$1,020,680	17,670	57.8
4	2016	$1,042,502	17,715	58.8
5	2017	$1,057,741	17,664	59.9
6	2018	$1,072,292	17,661	60.7
7	2019	$1,054,689	17,132	61.6
8	2020	$1,101,654	17,718	62.2
9	2021	$1,111,632	17,701	62.8
10	2022	$1,127,536	17,715	63.6
11	2023	$1,142,524	17,728	64.4
12	2024	$1,053,528	16,209	65.0
13	2025	$176,462	2,867	61.5
14	2026	NA	NA	NA
15	2027	NA	NA	NA
16	2028	NA	NA	NA
17	2029	NA	NA	NA
18	2003 PV	$3,147,942	NA	60.3

E. Combined Cycle Generation Cost Scenario

The second scenario was one where PG&E contracts or builds 2200 MW of new combined cycle generation to be on-line by the date when the DCPP Units 1 and 2 are expected to be shut down. The cost of new combined cycle generation has two major components: (1) fixed capital-related and fixed operations and maintenance (O&M)-related costs, (2) and operating costs.

1. Fixed Capital-related Costs

Fixed capital costs are associated with siting, permitting, financing and building new generation, including the cost of gas and electricity infrastructure for the new generation. PG&E relies on the CEC's combined cycle construction cost estimate. The CEC's estimate is low because it includes no interconnection or transmission network upgrade costs.

Consistent with current Federal Energy Commission (FERC) policy, a power plant developer is responsible for system interconnection costs, including direct assignment facilities (or generation tie) costs, which are needed to connect the resource to the network.

Fixed costs also include network upgrades, which are facilities that may be needed to accommodate the generation beyond the generation tie's connection to the network. Network upgrade facilities include transmission lines, transformer banks, special protection systems, substation breakers and other equipment that is needed to transfer power to the consumers. Because network upgrades are not used exclusively by the new generation, electric consumers ultimately pay the costs of these facilities through transmission rates. Being borne ultimately by consumers, network upgrade costs must be included as part of the cost of alternative generation.[6]

Fixed costs also include fixed O&M costs such as wages and salaries of full time staff, insurance costs, and property costs, etc.

2. Operating Costs

Operating costs include the cost of fuel and other supplies used by the new combined cycle units, as well as the variable O&M costs. Combined cycle plants are generally considered baseload generation that closely resembles the generation pattern of the DCPP Units. However, because PG&E is assumed to contract or build 2,200 MW of new combined cycle generation, rather than the expected 2,260 MW output of the DCPP Units, and because of the different operating characteristics of DCPP and the combined cycle units, such as different forced outage rates and planned outage schedules, the volume of generation from the combined cycle units may at times differ from that of the DCPP Units. These differences in generation are valued at the forecast energy prices, and are included as part of operating costs. For example, if at a given time, the combined cycle units produce less energy than the DCPP Units, that additional generation is "purchased" at forecast energy prices. In addition, a new combined cycle generating plant built to replace DCPP generation will have a life that extends beyond the date when replacement energy would be needed even with steam generator replacement (i.e., the expected license life of DCPP Units 1 and 2).

In this analysis, the capital cost of new combined cycle generation is levelized over its expected life. The combined cycle capital cost and its fixed and variable operating costs through 2029 are included in estimating

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[6] Under current FERC policy, the utility has the option to require the developer to fund the network upgrades and be repaid, with interest, after the new generation is operational.

this alternative's costs. Beyond 2029, the difference between the Project's continuing costs and the value of its generation is assumed to be approximately equal and therefore not considered.

For purposes of analyzing the Projects, PG&E has assumed that with the steam generators replacement the DCPP Units will retire at the end of the expected license life for each Unit.[7]

3. Resulting Alternative Combined Cycle Costs

Table 6-5 summarizes the alternative combined cycle generation cost both in $ per year and $/MWh. The cost reflects replacement of power from both Units 1 and 2 as of the dates that each is expected to be shut down through its expected license termination.

TABLE 6-5
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE COMBINED CYCLE COST

Line No.	Year	Fixed capital & O&M cost, $000	Operating costs, $000	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$108,616	$334,546	$443,162	7,744	57.2
2	2014	$229,682	$716,122	$945,804	16,335	57.9
3	2015	$240,893	$791,594	$1,032,487	17,670	58.4
4	2016	$242,077	$804,003	$1,046,080	17,715	59.1
5	2017	$243,290	$812,456	$1,055,746	17,664	59.8
6	2018	$244,533	$825,013	$1,069,547	17,661	60.6
7	2019	$245,808	$805,258	$1,051,066	17,132	61.4
8	2020	$247,114	$849,912	$1,097,026	17,718	61.9
9	2021	$248,453	$857,421	$1,105,874	17,701	62.5
10	2022	$249,826	$870,698	$1,120,524	17,715	63.3
11	2023	$251,232	$884,616	$1,135,849	17,728	64.1
12	2024	$252,674	$794,405	$1,047,080	16,209	64.6
13	2025	$254,152	$(84,021)	$170,131	2,867	59.3
14	2026	$255,667	$(261,990)	$(6,322)	NA	NA
15	2027	$257,220	$(263,641)	$(6,421)	NA	NA
16	2028	$257,220	$(270,233)	$(13,012)	NA	NA
17	2029	$257,220	$(276,988)	$(19,768)	NA	NA
18	2003 PV	$889,507	$2,259,939	$3,149,446	NA	60.3

F. Combined Cycle and Renewable Generation Cost Scenario

In this scenario, PG&E substitutes 10 percent of new combined cycle generation in Scenario 2 (described above) with renewable generation when the

[7] Unit 1's license is expected to be extended and then expire on November 2, 2024, and Unit 2's expires on April 26, 2025.

DCPP Units 1 and 2 are shut down. Renewable resources are primarily provided by wind, geothermal and solar renewable technologies. Because renewable generation does not have a similar level of reliability or delivery profile as DCPP or generic combined-cycle resources, PG&E does not estimate the impact of replacing all of DCPP's generation with renewable resources. Instead, PG&E estimates in this section the alternative replacement power cost when substituting 10 percent of combined cycle generation with an equivalent energy amount of renewable resources. The CEC Staff generation technologies report was used as a reference for the cost of renewables. That report suggests that solar energy is much more costly than either wind or geothermal, so solar was not reflected in this analysis. Geothermal generation may be cost-competitive with wind depending on whether it is "flash" or "binary" technology. Because of questions about the quantity of geothermal "flash" technology sites in California, this analysis focuses on wind energy as the renewable resource to be analyzed.

1. Wind Costs

This analysis adopts the cost of the wind farms as published in the above-referenced CEC report. In this analysis the DCPP generation replacement is 17,818 GWh (approximately a 90 percent capacity factor) of which 1732 GWh is from wind generation. At the 40.2 percent capacity factor assumed by the CEC for wind, there is a need for 492 MW of installed wind capacity.[8] The remaining energy needs are assumed to come from combined cycle generation and market purchases. Based on a 90 percent availability factor (5 percent for forced outages and 5 percent for maintenance outages), 1977 MW is from installed combined cycle generation.[9] Therefore, there would be a need to have 1977 MW of combined cycle generation, 492 MW of wind capacity, and a small amount of market purchases to replace the DCPP generation.

While PG&E has used the CEC's August 2003 wind cost estimates for purposes of its cost-effectiveness analysis in this testimony, PG&E does

[8] Ten Percent of 17,320 GWh per year divided by 8,760 hours at a 40.2 percent capacity factor.

[9] 90 percent of 17,320 GWh per year divided by 8,760 hours and a 90 percent capacity factor.

have a few reservations about these estimates and believes they understate the costs of wind generation. We list these reservations in order to preserve PG&E's position but it is not necessary to address these issues in this proceeding given the robust cost-effectiveness showing that results using the CEC estimates without adjustment. First, the CEC report assumes a wind capacity factor of 40.2 percent. Data collected by the CEC suggests that an assumption of 30 to 35 percent annual capacity factor for new wind turbines is a more reasonable assumption. Second, given the intermittent nature of wind, replacement costs are higher because of the need to firm up wind generation to achieve the same level of dependable capacity as the other alternatives. Finally, as indicated before, the CEC did not include the cost of transmission lines and substations.

As with the prior alternative, new combined cycle generating plant and wind farms built to replace DCPP generation have lives that extend beyond the expiration of the Nuclear Regulatory Commission (NRC) licenses for DCPP Units 1 and 2. In this analysis, the capital cost of new combined cycle generation and the wind farm is levelized over their respective lives, and the energy produced by the combined cycle/wind generation is credited against project cost through 2029. Beyond 2029, the differences between the combined cycle/wind project continuing costs and the value of such generation are assumed to be approximately equal and therefore not considered.

2. Resulting Alternative Renewable Costs

Table 6-6 summarizes the alternative renewable generation cost for wind, both in $ per year and $/MWh. The cost reflects replacement of 10 percent of power from each Unit 1 and 2 from the dates the units are shut down through the year 2029, with energy credits given for the period after the end of license of each DCPP Unit.

TABLE 6-6
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE 90% CC AND 10% RENEWABLE COST

Line No.	Year	CC costs, (includes balancing cost) $000	Renewable costs, $000	Total annual costs, $000	Annual generation, GWh	Average annual cost, $/MWh
1	2013	$393,900	$48,125	$442,024	7,744	57.1
2	2014	$845,144	$97,980	$943,125	16,335	57.7
3	2015	$929,493	$99,751	$1,029,244	17,670	58.2
4	2016	$941,554	$100,778	$1,042,332	17,715	58.8
5	2017	$950,078	$101,830	$1,051,908	17,664	59.6
6	2018	$962,695	$102,908	$1,065,603	17,661	60.3
7	2019	$943,026	$104,014	$1,047,039	17,132	61.1
8	2020	$987,794	$105,147	$1,092,941	17,718	61.7
9	2021	$995,447	$106,308	$1,101,755	17,701	62.2
10	2022	$1,008,896	$107,499	$1,116,395	17,715	63.0
11	2023	$1,022,812	$108,719	$1,131,531	17,728	63.8
12	2024	$932,627	$109,970	$1,042,597	16,209	64.3
13	2025	$54,254	$111,252	165,506	2,867	57.7
14	2026	$(123,631)	$112,566	$(11,065)	NA	NA
15	2027	$(125,170)	$113,913	$(11,257)	NA	NA
16	2028	$(134,087)	$115,294	$(18,793)	NA	NA
17	2029	$(143,226)	$116,709	$(26,517)	NA	NA
18	2003					
	PV	$2,754,238	$380,868	$3,135,105	NA	60.1

G. Other Risks and Costs Associated with the Alternative Generation Scenarios

1. Additional Replacement Costs and Risks

In the event that the Projects are not implemented, there would be uncertainty as to: (1) the exact time when the Diablo Canyon units may need to be shut down, and (2) the increased probability of extended forced outages as explained in Chapter 5. These uncertainties would translate into an unknown schedule for building or contracting to purchase replacement generation, and ultimately into the possibility of higher than anticipated replacement power costs, and adverse reliability impacts if not enough resources are available in the market to replace a DCPP unit forced to shut down. If, for example, one of the two Units must shut down before new generation is built or contracted by PG&E, there would be an increase in market prices paid by PG&E to meet its open position.

Conversely, if the DCPP Units continue to operate beyond their expected shutdown dates, and new generation is built or purchased for operation before those dates, customers would be exposed to paying for replacement generation that may not be needed and that may need to be sold at less than cost as surplus sales.

In Table 6-7, PG&E provides an estimate for years 2013 through 2016 of the additional cost of purchasing from the market if replacement generation is not built by the time the DCPP Units are shut down, relative to the market purchase estimate presented in Section C. To prepare this estimate, PG&E forecasted market prices via MARKETSYM simulations excluding the DCPP Units and replacement combined cycle generation.

TABLE 6-7
PACIFIC GAS AND ELECTRIC COMPANY
INCREASE IN REPLACEMENT COSTS DUE TO RISK OF EXTENDED OUTAGES OR EARLY SHUTDOWN OF THE NUCLEAR UNITS, $000

Line No.	Year	$000
1	2013	$9,206
2	2014	$36,616
3	2015	$37,631
4	2016	$39,120

2. Increased Emissions

If the DCPP Units are shut down and generation is replaced with gas-fired combined cycle generation, one would expect there to be increases in air emissions in California and the WECC system. Since natural gas is a fairly clean-burning fuel, there would be little increase in sulfur dioxide (SOx) or nitrous oxide (NOx) emissions on a WECC-wide level, although local air sheds may show meaningful impacts. WECC wide, carbon dioxide (CO2) emissions are expected to increase significantly. Annual differences in CO2 emissions (in thousands of tons) between DCPP generation and combined cycle generation is shown in Table 6-8 below.

TABLE 6-8
PACIFIC GAS AND ELECTRIC COMPANY
WECC-WIDE CO2 EMISSIONS IF DCPP GENERATION IS REPLACED WITH COMBINED CYCLE COMBUSTION TURBINE GENERATION (THOUSAND OF TONS)

Line No.	Year	WECC-wide CO2 Emissions With Diablo ktons	WECC-wide CO2 Emissions Without Diablo ktons	Difference ktons
1	2013	470,867	477,938	7,071
2	2014	479,135	486,541	7,406
3	2015	486,690	494,074	7,384
4	2016	495,719	503,102	7,383
5	2017	504,521	511,150	6,630
6	2018	513,069	519,766	6,697
7	2019	521,762	528,528	6,765
8	2020	530,603	537,437	6,834
9	2021	539,594	546,496	6,902
10	2022	548,737	555,709	6,971
11	2023	558,372	565,331	6,959
12	2024	568,150	575,120	6,971
13	2025	578,100	585,080	6,981
14	2026	588,225	595,214	6,989
15	2027	598,529	605,525	6,995
16	Total			104,938

H. Summary of the Alternative Cost Scenarios

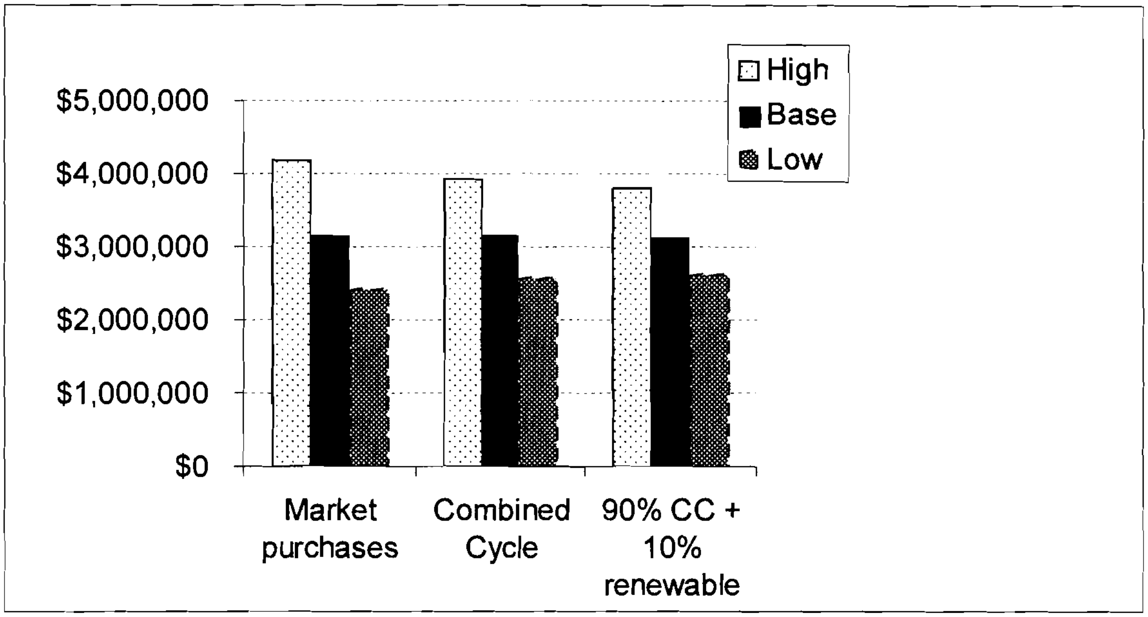
Table 6-9 compares the alternative demand/supply costs based on the assumptions set forth above:

TABLE 6-9
PACIFIC GAS AND ELECTRIC COMPANY
BASE GAS PRICE CASE RESOURCE COSTS, $000

Line No.	Year	Market purchases	Combined cycle generation ("100% CC")	90% CC plus 10% MW renewable generation
1	2003 PV	$3,147,942	$3,149,446	$3,135,106

Figures 6-1 summarizes the cost of alternative resources under various natural gas price assumptions:

FIGURE 6-1
PACIFIC GAS AND ELECTRIC COMPANY
COST SENSITIVITY TO GAS PRICES



As shown in Table 6-9 and Figure 6-1, all the generation alternatives considered have costs that are similar if not higher than the estimated cost of purchasing power to replace DCPP at the projected market prices. As expected, market purchase costs show the greatest sensitivity to natural gas price uncertainty. Therefore, for purposes of analyzing the robustness of the proposed Projects it is reasonable to use the range of market price forecasts presented in Section D of this chapter.